Cover Page

Exhibit 9.11

Presented during cross-examination

of Staff witness James B. Petersen

Docket No. 6680-UR-117

Public Service Commission of Wisconsin

Daniel R. Ebert, Chairperson
Robert M. Garvin, Commissioner
Mark Meyer, Commissioner

610 North Whitney Way
P.O. Box 7854
Madison, WI 53707-7854

August 17, 2006

To the Service List

RE: Investigation on the Commission's Own Motion Regarding Principles Useful in Electric Cost-of-Service Studies and Rate Design — 5-EI-137

Comments Due:	Address Comments To:
Tuesday, September 12, 2006 – Noon	**Sandra J. Paske**
	Public Service Commission
This docket uses the Electronic Regulatory	P.O. Box 7854
Filing system (ERF).	Madison, WI 53707-7854

The Briefing Memorandum in this docket is being provided to the participants for comment. Comments must be received by Tuesday, September 12, 2006, at noon. Comments must be filed using the Electronic Regulatory Filing (ERF) system. The ERF system can be accessed through the Public Service Commission's website at http://psc.wi.gov.

Sincerely,

/s/ Robert Norcross

Robert Norcross
Administrator
Gas and Energy Division

RDN:jlt:L:\05-EI-137\request for briefing memo comments 8-17-06.doc

Enclosure

PUBLIC SERVICE COMMISSION OF WISCONSIN
Memorandum

August 17, 2006

TO: The Commission

FROM: Robert Norcross, Administrator
Donna Holznecht, Assistant Administrator
John Feit, Financial Analyst
James Petersen, Senior Rate Engineer
Jerry Albrecht, Senior Rate Engineer
Gas and Energy Division

RE: Investigation on the Commission's Own Motion Regarding Principles Useful in Electric Cost-of-Service Studies and Rate Design 5-EI-137

BRIEFING MEMORANDUM

DOCKET INTRODUCTION

Among the most important issues that the Commission regularly deals with in rate cases are cost-of-service studies (COSS) and rate design. The Commission has found that the COSS filed by the utilities and Commission staff, along with related input from customer groups result in such a wide range of divergence that they become of diminished usefulness in the decision-making process. The Commission has not taken the position that there is one correct COSS; however, it does believe that there are opportunities to narrow the range of differences so that COSS can significantly contribute to effective rate design. The purpose of this investigation is to determine whether or not COSS differences can be narrowed in electric utility rate cases and to get ideas on innovative ratemaking so that customers are given proper price signals that benefit not only them but the utility system as a whole.

On July 29, 2005, the Commission issued a notice in this docket and asked for comments on a Commission staff report that discussed COSS and rate design issues. This memorandum assumes some familiarity with the COSS concepts discussed in that report. Comments were received from utilities and customer groups on August 29, 2005, and reply comments were received on September 12. Given the existing caseload at that time, the Commission and stakeholders to the investigation decided to put the issues in the docket aside until the first part of 2006. Technical conferences were held on March 31 and May 3, 2006. During the course of those conferences documents related to COSS and rate design were exchanged between the stakeholders.

This memorandum is divided into two sections, one on COSS and the other on rate design.

Electric COSS

Introduction

During the comment period and the technical conferences Commission staff and parties identified many areas that affect the results of an electric utility COSS. However, there are nine areas that appear most critical in terms of substantive impact on the COSS. If Commission direction can be given on these nine areas, chances of narrowing the differences between the parties could be enhanced. The focus on this section of the memorandum will be on those nine areas. They are as follows:

1. Should production costs be allocated using both demand and energy allocators?
2. A 12 coincident peak (CP) demand allocator is used in Commission staff's and most of the utilities' COSS. Is there a better allocator that should be used?
3. How should interruptible loads be treated in the COSS?
4. How should fuel expenses be allocated?
5. Which allocator should be used for purchased power costs?
6. How should transmission costs be allocated?
7. Assuming agreement on the Minimum System method as the proper allocator of distribution costs, how should the allocator be calculated?

8. Should energy efficiency costs be directly assigned to the customer class incurring the costs or should they, all or in part, be allocated to all customer classes?
9. How should common costs be allocated?

Each of these issues will be discussed in turn, identifying the positions of the stakeholders at the technical conferences (stakeholders) and possible resolutions for the specific issues.[1] At the end of this section are suggested alternatives for addressing each of the COSS topics. For several of the issues there is agreement, or at least near agreement, among the stakeholders. A brief summary of positions by the stakeholders on each of the nine issues is included in Appendix A.

1. Should production costs be allocated using both demand and energy allocators?

Given the high capital and operating costs of power plants, it is not surprising that production costs make up a substantial amount of a utility's revenue requirement. That amount becomes even greater when factoring in the effect that production costs has on the allocation of common costs. When applying cost causation principles the relevant question is whether customer demand alone drives the incurred cost of power production, or if energy use also affects those costs.

Commission staff's several COSS have generally reflected an allocation of production costs on the basis of both demand and energy. That allocation assumes that peaker plants are 100 percent demand related, intermediate load plants are approximately 80 percent demand related, and baseload plants are approximately 50 percent demand related. Overall, Commission staff then allocates production costs at 60 percent on the basis of demand and 40 percent on the basis of energy.

[1] In addition, a late-emerging issue relating to the allocation of income taxes is also presented.

Wisconsin Electric Power Company (WEPCO), Northern States Power Company-Wisconsin (NSPW), Wisconsin Public Power Inc. (WPPI), and the Citizens' Utility Board (CUB) also take the position that production costs should be allocated on the basis of demand and energy, although would do so by applying different percentages. WEPCO would allocate these costs at 63 percent on demand; NSPW 44 percent on demand; and CUB 40 percent on demand. WPPI has not advocated a specific allocation because of the nature of municipal utility purchased power costs.

WEPCO's demand allocation of 63 percent was determined using the Equivalent Peaker method to assign the portion of the plant that should be allocated using demand. Commission staff used this method to calculate demand allocation percentages of 62 percent, 64 percent, and 44 percent for Wisconsin Public Service Corporation (WPSC), Wisconsin Power and Light Company (WP&L), and Madison Gas and Electric Company (MGE), respectively, in dockets before the Commission in 2006.

Proponents of the demand and energy allocation argue that the capital cost of a baseload plant is greater than that of other power plants but the energy costs are lower. Therefore, the decision to build a baseload plant is made to capture lower energy costs for customers. Recent decisions to build coal plants were driven by the annual increase in base energy usage, a circumstance for which it would not have been economical to build peaker or intermediate load power plants.

WP&L, WPSC, MGE, Wisconsin Industrial Energy Group (WIEG), and Wausau Paper take the position that production costs should be allocated on the basis of demand alone. This position is based on the belief that utilities build power plants, whether they be baseload, intermediate, or peaker plants, to meet customer demand. Since it is those demand characteristics that drive the need for new power plants the associated costs should be allocated on demand. Wausau Paper believes that allocating production costs partially on the basis of energy use and also setting energy rates at the marginal energy cost is essentially a double count resulting in unfair rates for high load factor customers.[2] To mitigate this effect, Wausau Paper believes that any or all of the following would solve the problem: (1) allocate production costs strictly on demand; (2) base large commercial and industrial energy rates on average energy costs, not on marginal energy costs; and/or (3) create a separate service class for high load factor customers. WIEG would be amenable to allocating a portion of fixed production costs on the basis of energy so long as the resulting demand portion of these fixed costs is allocated on the basis of a demand allocator different than the 12 CP method.

Typically, large commercial and industrial customers will be allocated more costs than residential and small commercial customers when a COSS includes an energy allocation of production costs than if these costs are allocated entirely on the basis of demand.

In several recent rate cases the Commission has indicated that an allocation of production costs should include both and energy and demand allocators, usually about two-thirds based on demand and one-third based on energy.

2. A 12 CP demand allocator is used in Commission staff's and most utilities' COSS. Is there a better allocator that should be used?

The 12 CP allocator is calculated by taking each customer class's share of total load at the time of each month's peak demand. The sum of these 12 monthly peaks is used to allocate

[2] Wausau Paper argues that by setting industrial energy rates on the marginal cost of energy, which is higher than the average cost of energy, especially if the plant is allocated only on the basis of demand, total COSS allocated energy costs are overcollected in rates for that customer class. Therefore, demand charges are often reduced below the level assigned in the COSS so that industrial rates more closely recover all allocated costs. This, Wausau Paper maintains, is an unfair result to high load factor customers. The counter-argument is that setting energy rates below the marginal cost of energy does not give the proper price signal.

coincident peak demand costs among the customer classes. Commission staff and the utilities have used the 12 CP allocator in their COSS and CUB supports this method, although WP&L has submitted a COSS using a 4 CP method (summer months only) in the past, and several proponents of the method believe there may be a different number of peak periods that could be superior to the 12 used now. WIEG and Wisconsin Paper Council (WPC) favor the 4 CP method. Wausau Paper would use a non-coincident peak demand approach. Mr. David Shutes, a member of the public representing himself, suggested that using coincident peak data for each hour of the year would be the most accurate way to calculate the demand allocator.

Proponents of the 12 CP allocator believe that it is important to include demand data in the allocator for each month of the year since the non-summer months are typically when planned outages occur and the system must be carefully designed to balance these outages and customer demand. However, this is not to say that using more than 12 CPs would be unreasonable. In fact, there is reason to believe having more data points would be an improvement.

A question that came up in this regard at the technical conferences was whether additional data could be developed by the utilities without excessive effort. A data request was sent to the utilities that asked for several variations of CP data from a single coincident peak to three hundred such peaks. Obtaining some of the more complicated aspects of that data request is still being pursued. Since all stakeholders at the technical conferences were open to analyzing additional CP options, this issue is ripe for further review.

The Commission could ask that COSS filed by Commission staff and utilities include the traditional 12 CP allocator and at least another method with more data points for comparison. Variations of the 12 CP method included 1 CP, 4 CP, the top 100 and 300 hours of peak demand, the top 10 CP for each month, and available system capacity at the time of the highest 100 and 300 CP demand hours. WEPCO was able to provide much of the information in the data request. The following chart shows the effect on cost allocations under the different CP alternatives, using WEPCO's CP data response, and applying it to WPSC's industrial class in rate case. Although there is obvious incongruity in the comparison it does provide some context for assessing the impact of different methods.

CP hours	Percent allocated to industrial class	$ Effect compared to the 12 CP method	Percent effect on the industrial rev. requirement
1	43.7%	-$21 million	-9.8%
4	45.7%	-$14 million	-6.5%
12	49.5%	-0-	-0-
100	46.1%	-$13 million	-6.0%
300	47.5%	-$ 7 million	-3.2%

3. How should interruptible loads be treated in COSS?

By having interruptible loads on its system a utility is able to avoid or delay building power plants. Rather than having power available at certain peak demand periods for interruptible customers the utility can simply shut off power to those customers. Commission staff's COSS includes interruptible load in the calculation of the demand allocator. Under this approach interruptible customers would initially be allocated costs associated with all types of power production facilities. To compensate the interruptible customers for the ability to interrupt their service, Commission staff's COSS gives an interruptible credit to these customers that is based on the cost of a peaker plant. By removing the cost of peaker plants from the interruptible customers' cost of service it recognizes the utility's ability to interrupt customers for a limited number of hours, typically up to 300 hours per year, or about 3.5 percent of all hours. Similarly, peaker plants are used infrequently so the rate credit for the interruptible load is based on the value of avoiding the need to construct peaker plant facilities. WEPCO, NSPW, CUB, and WPPI also subscribe to this method of treating interruptible loads in the COSS.

WP&L, MGE, WPSC, WIEG, WPC, and Wausau Paper take the view that a utility does not incur any capacity cost—baseload, intermediate, or peaker—for load that is interruptible. It is the condition of interruptibility and not the frequency of interruptions that lead to lower capacity costs. They argue that COSS that allocate a portion of production plant on the basis of energy are already assigning capacity costs to interruptible customers even without including demand in the demand allocator.

As discussed previously, Commission staff's COSS does not allocate the costs of peaker plants on the basis of energy. Only a small portion of intermediate plants are allocated based on energy use. Therefore, it appears that the condition of interruptibility is the driving force behind those that argue against the Peaker Method.

4. How should fuel expenses be allocated?

Fuel expense is an area where consensus was reached that kilowatt hour (kWh) sales is the proper basis for determining the allocator. Stakeholders also agreed that fuel expenses should continue to be reviewed as to whether the energy allocator should be weighted to reflect time-of-use. Since different kinds of fuel have different time-of-use tendencies and some customer classes have time-of-use rates there could be further cost causation effects that warrant consideration. WEPCO and NSPW indicated that they have analyzed a time-of-use allocator and found there to be little change from the simple energy allocator, but acknowledged that continued review, particularly with the implementation of the Midwest Independent Transmission System Operator (MISO) market, is appropriate.

5. Which allocator should be used for purchased power costs?

All stakeholders agreed that purchased power costs should be allocated in a manner consistent with the specific purchase. That is, purchases that are intended to satisfy baseload, intermediate or peaking needs should be allocated on a basis consistent with the allocation of similar power plants owned by the utility. The related issues that remain unresolved, however, are whether or not interruptible load would be included in the calculation of the demand allocator (Issue 3), and whether there is a better allocator than the 12 CP method currently used (Issue 2).

6. How should transmission costs be allocated?

On this issue there is also little controversy. All stakeholders, with the exception of Wausau Paper, agreed that using a coincident peak demand allocator was appropriate, which is the basis upon which the utilities are billed from MISO. Wausau Paper prefers the noncoincident demand allocator. The best coincident peak demand allocator (Issue 2) would still need to be resolved. WP&L appears to be the only participant that favored exclusion of interruptible demand from the calculation of the demand allocator when assigning transmission costs to the customer classes (Issue 3). All stakeholders agreed that review of the continued use of the demand allocator should continue as the MISO market evolves to ensure proper application of cost causation principles.

7. Assuming agreement on the Minimum System method as the proper allocator of distribution costs, how should the allocator be calculated?

All stakeholders except CUB and some Commission staff believe the Minimum System method should be used when allocating distribution system costs. Under the Minimum System method utility records are analyzed and an estimate of the smallest unit commonly installed is calculated. This unit then becomes defined as a customer cost and the remainder of costs are allocated on the basis of demand. The Minimum System method is founded on the principle that distribution system costs vary by the number of customers as well as demand. A flaw in this method is the absence of agreement on the percentages assigned to demand and weighted customers. For example, WEPCO allocates 94 percent of its distribution system costs on the basis of demand and 6 percent on the basis of weighted customers. WP&L allocates 19 percent of the costs on demand and 81 percent on the basis of weighted customers. While some variance is to be expected with different service territories, those differences should be much narrower. This suggests that the method allows for too much discretion in its calculation. To address this deficiency, stakeholders suggested a detailed review of the calculation of the allocators should take place so that a more consistent application of the method is developed. Another suggestion was to simply use a 50-50 cost split between demand and weighted customer allocators. This approximately represents the average percentages of the five large investor-owned utilities and acknowledges that both factors play a significant role in the distribution system cost causation.

CUB advocates use of the Location method which allocates distribution system costs strictly on the basis of non-coincident demand. CUB and some Commission staff believe that the Minimum System method allocates too few of the distribution system costs to the large customers. The Location method allocates a much greater proportion of distribution system costs to large users and assumes that the number of customers is not the primary cost causer.

8. Should energy efficiency costs be directly assigned to the customer class incurring the costs or should they, all or in part, be allocated to all customer classes?

The discussion on the allocation of energy efficiency costs at the technical conferences focused on two methods: direct assignment and partial sharing of costs. Under the direct assignment method, which was favored by all stakeholders except Wausau Paper and WPPI, energy efficiency costs are allocated to the customer classes that are incurring the costs; or stated another way, receiving the direct benefits of the energy efficiency programs. The argument for this method is premised on the idea that a successful energy efficiency program targeted to a customer class will decrease that class's demand and/or energy allocator(s) thereby decreasing the amount of costs allocated to the class. Therefore, since the customer class receives benefits of the energy efficiency programs through this cost allocation process, it should be responsible for the program's cost.

The argument for allocating energy efficiency costs to all customer classes regardless of which ones are incurring the costs is that all customers benefit from a customer's more efficient use of electricity through a decreased need for expensive infrastructure additions. Since all customers benefit, all of them should share in the cost of energy efficiency programs. Wausau Paper and WPPI support this position.

This issue warrants continued scrutiny as 2005 Wisconsin Act 141 is implemented. Also, in certain situations, such as WP&L's Shared Savings program, the amount of dollars that are attributable to a limited number of customer classes is sometimes large and can have a significant impact on a COSS. WP&L and CUB, at a minimum, favor flexibility in how energy efficiency costs are reflected in COSS.

The Commission did address this issue in a recent WP&L rate case. In that decision Shared Savings costs were allocated 50 percent to the customer classes directly benefiting from the program and 50 percent across all classes on the basis of demand.

9. How should common costs be allocated?

Common costs are those that do not have clear cost causation qualities and are generally allocated using an indirect allocator. The total amount of these costs in a utility revenue requirement are substantial. Many Administrative and General expenses are common costs. All stakeholders at the technical conferences, except for CUB, advocate allocating common costs to customer classes in the same proportion as the sum of all other allocated costs, except fuel and purchased power costs, or on the basis of direct labor. Both of these indirect allocators assume that common costs are incurred to support all utility operations; therefore, the costs are allocated similarly.

CUB took the position that since there is not a direct cost causation relationship for these costs they should be allocated on the basis of energy use. Presumably, CUB is taking the position that energy use is the default for cost allocation.

Everyone agreed that efforts should continue to establish direct cost causation links for as many indirect costs as possible.

A Late-Emerging Issue

Subsequent to the technical conferences Commission staff took a closer look at the allocation of income taxes. This cost has traditionally been allocated on the basis of net investment rate base, presumably because the amount of authorized net income is a function of rate base and income taxes are function of net income. Commission staff is considering whether it is more appropriate to allocate income taxes on the basis of taxable income by customer class. Under this approach, revenues and expenses are allocated to each class with the result being taxable income by class. Applicable tax rates would then be applied to the taxable income to determine the allocation of income taxes by class at present rates. This result would serve as the basis for allocating income taxes at proposed rates. The difference in the allocation of costs can be significant between the two methods. Stakeholders at the technical conferences are invited to comment on this emerging issue.

Electric COSS Summary

It is not realistic to expect the Commission to decide on a single COSS. Flexibility must remain the hallmark of a process impacted by so many critical variables. However, Appendix A shows that there is agreement or near agreement among the stakeholders to the technical conferences on several listed issues. Also, the Commission has recently indicated a preferred allocation method for production costs and, arguably, for energy efficiency costs. From the discussions at the technical conferences it appears that the two issues that have the most materiality and controversy, and that have not been specifically addressed by the Commission, are the calculation of the demand allocator (12 CP) and the inclusion or exclusion of interruptible demand in the demand allocator. Some of the stakeholders appear to view a favorable resolution of these two issues and a revised allocation of production costs as the remaining hurdles to achieving a consensus (or new consensus) approach to electric COSS.

Commission Alternatives

Alternative One: The Commission could indicate its preferred method of allocation for each of the nine items shown in the appendix.

Alternative Two: The Commission could direct utilities and Commission staff to submit a COSS in electric rate cases, in addition to any other COSS they choose to file, for each of the nine issues as follows:

Issue 1: Allocate production costs two-thirds on the basis of demand and one-third on the basis of energy.

Issue 2: Compute the demand allocator using the 12 CP method.

Issue 3: Include interruptible load in the calculation of the demand allocator.

Issue 4: Allocate fuel expense on the basis of energy use.

Issue 5: Allocate purchased power on a consistent basis with the signed contract – baseload purchases 50 percent demand, 50 percent energy; intermediate load purchases 80 percent demand, 20 percent energy; peak load purchases, 100 percent demand.

Issue 6: Allocate transmission costs on the basis of coincident demand.

Issue 7: Allocate distribution costs 50 percent on demand and 50 percent on weighted customers at least until a satisfactory resolution of the different results of the utilities' application of the Minimum System method is reached.

Issue 8: Allocate energy efficiency costs to the customer class that is the direct recipient of the energy efficiency programs when that can be reasonably determined. Allocate any remaining costs on the basis of coincident peak demand.

Issue 9: Allocate common costs to customer classes in the same proportion as the sum of all other utility costs, except for fuel and purchased power costs.

In addition, the following should be provided:

1. The stand-alone customer class cost impacts of allocating production costs entirely on the basis of demand.
2. The stand-alone customer class cost impacts of calculating the demand allocator using significantly more than twelve data points.
3. The stand-alone customer class cost impacts of excluding interruptible load from the calculation of the demand allocator.
4. The stand-alone customer class cost impacts of allocating energy efficiency costs on the basis of 50 percent direct assignment and 50 percent on demand.

5. A demonstration of the effects of using time-of-day information for the allocation of fuel costs.

Alternative Three: Use the information in this docket as an aid in the ratemaking process but make no specific declaration on the nine issues.

Alternative Four: Direct Commission staff to reconvene the technical conference in order to get further information on specific issues.

Electric Rate Design Issues

Introduction

During the 1970s and 1980s, there was considerable activity nationally and in numerous rate proceedings before the Commission on electricity pricing. This period was characterized by significant increases in electric rates and concerns about the environmental impact of the electric utility industry. There was considerable interest by the Commission in developing rates that properly reflected short-run and long-run marginal costs so that electric rates sent accurate price signals to consumers. During this period, the Commission required the implementation of interruptible rates as an option for industrial customers and adopted a method of determining a rate credit for interruptible service, mandated time-of-day rates for customers with demand greater than 200 kilowatts (kW), mandated optional time-of-day rates for residential and small commercial customers and approved direct load control programs for residential customers.

The early to mid-1990s can be characterized as a period of declining or relatively static electric prices. There was less emphasis on marginal costs and the implementation of new rate structures during this period, although the Commission did approve several real time pricing programs and modifications to the interruptible rate schedules.

During the past several years, electric rates in Wisconsin and in some other states have increased significantly. These increases have drawn attention back to the importance of providing accurate price signals to customers so that electricity is used efficiently. In addition, the Commission has expressed interest in improving existing rate structures and implementing new rate alternatives so that customers have access to rate options that provide them with the opportunity to reduce their bills. In their joint comments submitted in this investigation, CUB and WIEG endorse the need to provide all customers with rate alternatives that will provide them with opportunities to reduce their bills and allow industrial customers to remain competitive.

The difficulty facing the Commission is that rate options that reduce an individual customer's bill must be matched by a corresponding reduction in the utility's costs. If not, in the short run, a utility may experience a reduction in profits because the loss of rate revenues will exceed the reduction in costs. In the longer term, the adoption of rate options could result in cost shifting among customers rather than lowering overall costs resulting in the more efficient use of electricity.

In April 2005, MISO implemented the Day 2 market. The Day 2 market provides transparent information on energy costs that will be useful in the design of electric rates. In the next several years, MISO will implement markets for other generation services such as planning reserves and operating reserves. This Day 2 market information will provide opportunities for the Commission to more accurately reflect costs in rates. This information can be used to develop new rate options that will provide opportunities for customers to consume more energy when costs are lower and to reduce their bills by reducing usage when costs are higher.

The written comments and the technical conferences on rate issues have allowed the stakeholders to study and clarify various rate-related issues and narrow the differences in their positions. Some rate options may be easy to design and implement. However, it is important to recognize that the costs to implement new rate structures and rate options including costs for metering, billing system modifications, and marketing can be significant and these costs must be considered given the shear numbers of customers served by the electric utilities who will pay for the implementation.

Residential and Small Commercial Rates

The stakeholders all support the implementation of new rate options for residential and small commercial customers. It is important to recognize that some of these rate options could require the installation of new metering equipment that provides hourly consumption data. Significant improvements have been made in metering technology. Several states have made investments in wide scale installation of new electronic meters for small customers. Several Wisconsin utilities have installed or are in the process of installing automated meter reading (AMR) systems. However, only the system installed by WPSC can provide hourly consumption data. The Commission may wish to investigate the availability and costs of new electronic metering technologies and what capabilities might be necessary to implement alternative rate structures for residential and small commercial customers.

CUB recognizes metering limitations but believes that average cost-based rates that are applicable over all hours of the year should be eliminated to the extent possible. CUB believes that small customers need additional rate options that reward them for changing their usage patterns from high cost periods to low cost periods and is particularly interested in integrating residential rates with direct load control options and in implementing other rate options for residential customers such as demand response rates and super peak pricing rates. CUB has been discussing rate alternatives with several utilities and feels that these discussions have been productive. CUB is likely to propose new rate alternatives for residential and small commercial customers in future rate cases.

Monthly Customer Charges

Residential and small commercial customers are typically served under a rate structure that includes a monthly customer charge and an energy charge per kWh. The level of the customer charge in relation to the energy charge is the most frequently contested rate design issue for the residential and small commercial classes. During the past five years, customer charges for the large utilities have been increased from a range of $5 to $6 per month to the range of $7 to $8 per month. These increases in customer charges have generally been in line with the percentage increases in energy charges over this period.

The customer charge is designed to reflect the fixed costs of providing customer service and to collect the costs for service facilities, such as transformers and meters. In general, utilities have argued that the current customer charges do not fully recover these fixed costs and have sought to increase the level of customer charges. Traditionally, Commission staff and CUB have supported relatively lesser increases in customer charges and greater increases in energy charges to encourage conservation and to protect small users from bill impacts.

There is no question that there is a positive elasticity of demand with respect to energy charges. Therefore, increasing energy charges by a greater degree than customer charges is likely to lead to more conservation investments by consumers. In other words, higher energy charges lead to a faster payback for conversation expenditures made by customers. This must be balanced with the principle that rate components should reflect costs. The Commission may wish to consider this issue as it examines other measures to provide customers with incentives to use energy more efficiently.

Time-of-Day Rates

Time-of-day rates have been available as an option for residential and small commercial customers since the early 1980s. Residential and small commercial time-of-day rates consist of a monthly customer charge and on-peak and off-peak energy charges. On-peak periods are typically 12 to 14 hours long during week days. The off-peak hours are the weekday overnight hours, and all day on weekends and holidays. In general, the stakeholders support the examination of new time-of-day rate options for residential and small commercial customers.

The relative number of customers taking service on time-of-day rates in Wisconsin has been stable. Many customers would likely save money on a time-of-day rate but are reluctant to take time-of-day service because of a lack of knowledge of their consumption patterns and a lack of promotion of time-of-day rates by the utilities. The Commission could require the utilities to increase customer awareness of time-of-day rates and to promote the availability of time-of-day rates as a way for customers to reduce their bills.

For many years the monthly customer charge for the time-of-day rate was set at approximately $1.00 per month higher than the standard customer charge. The higher customer charge has been a barrier to customer participation. Last year, in several rate cases, the Commission approved staff proposals to set the time-of-day customer charges at the same level as the standard residential customer charge. The elimination of the differential in the customer charge between the standard rate and the time-of-day rates is a small step that should encourage more customers to try time-of-day rates.

Another barrier to customer participation in time-of-day rates is the relatively long on-peak period. One possibility to reduce this barrier would be to develop a three period rate with a peak period and a shoulder peak period. This would increase the flexibility for customers to increase their consumption during the shoulder hours by offering a lower shoulder rate that would reflect the lower costs during these hours. Time-of-day rates with more than two pricing periods would require the installation of new meters for all utilities except WPSC.

Another possibility would be a three period rate with a super peak period. The super peak period rates would only be implemented on days when Location Marginal Pricing (LMP) is particularly high, such as during hot summer afternoons or cold winter afternoons and evenings. One problem with super peak time-of-day rates is that the days during which the super peak rate would be applied must be communicated in some manner to customers. Effective communication of the super peak time periods to participating customers could be problematic.

Energy charges for the time-of-day rates were originally established in an approximately 4 to 1 on-peak to off-peak ratio. This 4 to 1 ratio has generally been maintained. Time-of-day rate options could be developed with lower on-peak charges and higher off-peak charges. This would provide an option which customers could view as being less “risky” than the standard rate differential.

CUB believes that the current time-of-day rates are underutilized and that the Commission should require utilities to consider improvements to time-of-day rate designs and implement pilot programs. The Commission could encourage the implementation of new time-of-day rates as options in addition to the existing time-of-day rates. The Commission could require utilities to submit new time-of-day rate options in upcoming rate cases with the objective of implementing pilot programs so that a variety of new time-of-day rate alternatives can be evaluated.

Real Time Pricing

There has been some interest in other states in offering real time pricing to residential and small commercial customers. It is not clear if there would be interest from small customers in Wisconsin for taking service under a real time rate. The Commission could investigate the experience of other states in order to make a determination of the potential benefits of a real time pricing rate structure for smaller customers. Implementing real time pricing would require the installation of new meters for all utilities except WPSC.

Commission Alternatives

Alternative One: The Commission could direct staff and the utilities to investigate the availability and costs of new electronic metering technologies and what capabilities might be necessary to implement alternative rate structures for residential and small commercial customers.

Alternative Two: The Commission could order the utilities to increase customer awareness by residential and small commercial customers of time-of-day rates and to promote the availability of time-of-day rates as a way for customers to reduce their bills.

Alternative Three: The Commission could order the utilities to submit new time-of-day rate options in upcoming rate cases with the objective of implementing pilot programs so that a variety of new time-of-day rate alternatives could be evaluated.

Large Commercial and Industrial Rates

The structure of electric rates and the availability of rate options is an important issue for many large commercial and industrial customers because electricity costs are a significant portion of their total costs. Interest in electric rate issues has become even more important during the last several years as the general level of rates has risen significantly.

Industrial customers in particular are interested in additional rate structure options that provide them with the ability to reduce their bills and yet provide them with operational flexibility. In general, the cost to provide the sophisticated metering which is necessary to make these options available is not a significant issue for larger customers because such metering is already in place for large customers and metering costs make up such a small portion of the total costs. It is important to recognize that the Commission has implemented a significant number of new rate options for large customers during the past 20 years. Most of these options were specifically designed to provide flexibility to customers.

WIEG and Wausau Paper have been active and constructive stakeholders in the examination of rate issues for large commercial and industrial customers. WIEG's most important issues are compensation for load reductions (demand response), real time pricing and individual contracts. Wausau Paper is most concerned about the availability of coincident demand billing energy charges and high load factor rates.

Rate Unbundling

Large commercial and industrial customers in Wisconsin are typically served under a rate structure which consists of a monthly customer charge, an on-peak demand charge, a distribution demand charge (also referred to as a "customer demand charge") and on-peak and off-peak energy charges. The on-peak demand charge is only applied to the customer's maximum demand measured over a 15 minute period during the on-peak period.

WIEG suggests that further unbundling of industrial rate structures would provide more transparency to customers concerning which components of cost are changing and by how much. WIEG suggests that customers would like to know how much of a bill increase is caused by transmission costs as opposed to generation costs. WIEG also believes further unbundling would provide information to customers that would allow them to change their consumption in order to reduce their bills.

In general, utilities do not support further rate unbundling. First, they suggest that it would be difficult to develop the cost information that would result in additional unbundled rate components. Second, they contend that since customers do not have access to alternative suppliers, this information would be of little use to customers.

Separating the demand charge into a transmission component and a generation component may provide additional information to customers and could be done relatively easily. The Commission could direct the staff and the utilities to investigate this issue. However, it is more likely that efficiency benefits would result from further unbundling the current on-peak and off-peak energy charges into additional pricing periods. This issue will be discussed further below.

As noted above, a significant component of large commercial and industrial rates is the monthly demand charge that is based on each customer's maximum demand during a 15 minute period during each month. A significant shortcoming of this component is the fact that the 15 minute period during which the customer reaches their maximum demand may not be a period during which the consumption of electricity causes the utility to incur a concomitant cost. In addition, many customers incur significant costs for load management equipment and modifying their operating schedules in attempting to keep their maximum 15 minute demand as low as possible.

The 15 minute monthly maximum demand charge is an artifact of the early days of electric utilities when generation and distribution capacity was extremely limited. A 15 minute demand interval can probably be justified for the purposes of applying the customer demand charge. This is because the distribution facilities that are located close to the customer must be sized to meet the customer's maximum instantaneous demand and maximum demand during a relatively shorter period. In contrast, in wholesale markets, the time interval for measuring demand for generation and transmission costs is almost universally one hour. The Commission could consider an examination of alternatives to the current 15 minute time interval of demand for collecting generation and transmission costs.

Energy Charges for Industrial Rates

The most contentious issue relating to industrial rate design is the level of the energy charges. Customers with relatively higher load factors who use large amounts of energy benefit from lower energy charges and higher demand charges. Conversely, customers with relatively lower load factors who use less energy tend to benefit from relatively higher energy charges and lower demand charges.

During the 1980s, the Commission set a general policy of establishing industrial energy charges based upon an average of a five-year projection of on-peak and off-peak marginal energy costs. The Commission decided to base energy charges on marginal costs so that customers would make efficient decisions concerning the use of electric energy.

During the past several years, the use of a five-year forecast of marginal energy costs has become problematic because of the volatility of the cost of coal, natural gas and purchased energy. In addition, marginal energy costs have increased significantly because of the increase in gas prices and the increasing use of gas in combined-cycle and peaking plants. Setting rates based on these higher marginal energy costs would result in large bill impacts to large energy users.

WIEG currently argues that the use of marginal energy costs is unfair to customers with high load factors and that energy charges should be based on average costs. WIEG also believes that high load factor customers impose lower costs on the utility and there should be special rates for high load factor customers. This issue will be discussed further below.

Commission staff has proposed in several rate proceedings that LMPs might be used as the basis for industrial energy charges because the LMPs represent the costs to the utility of selling one more or one less kWh. Staff has suggested that it does not make sense for a utility to buy energy from the MISO market at one price and then sell the same energy at a different price, especially if the retail price is less than the LMP.

A demand charge is essentially an option payment that allows the customer to purchase on-peak energy at a certain rate. One possible alternative to the current rate structure would be to offer customers several different demand charges each with an associated on-peak energy charge. A high demand charge would allow customers to purchase energy at a lower rate, while a lower demand charge would be associated with a higher energy charge. Such a formula rate would allow customers with high load factors to have the high demand charge–low energy charge rate structure they desire without causing severe bill impacts to customers with low load factors. One possible middle ground would be to set the on-peak demand charge based on the cost of a combined-cycle unit and set energy costs based on combined-cycle energy. Since there is no demand charge during the off-peak hours, energy charges during these hours should be based on the off-peak LMPs.

In order to ensure the energy prices send accurate price signal to customers, the energy prices must reflect costs. An analysis of the LMPs in the Day 2 market should be performed to determine whether the on-peak and off-peak periods adopted by the Commission almost 25 years ago are outdated. The two pricing period rate design was originally adopted because costs were perceived to be either "on-peak" or "off-peak" and because of the limited capability of metering equipment. The MISO energy market now provides hourly prices and it may be appropriate to further "unbundle" energy prices into additional periods. Additional pricing periods would provide more efficient price signals to customers. The Commission could investigate the use of additional pricing periods so that energy charges can more closely match market costs.

High Load Factor Rates

Customers with high load factors use relatively large amounts of electric energy in relation to their demand. Customers such as paper mills that operate around the clock typically have high load factors. Foundries with large electric furnaces which operate for relatively short periods of time typically have relatively low load factors.

WIEG and Wausau Paper argue that customers with high load factors impose lower costs on the utility and thus should receive special rate consideration. The Commission has approved rate provisions which provide a discount for high load factor customers for NSPW and for WP&L.

Whether customers with high load factors are paying in excess of the cost they impose on the utility is dependent on the level of the maximum demand charge. WEPCO points out the type of rate structures that the Commission has adopted during the past 20 years which incorporate relatively high demand charges and lower energy charges effectively provide a rate discount for customers with higher than average load factors. The Commission could decide to conduct an analysis of high load factor customers in order to determine if these customers impose lower costs on the utility. As pointed out by WEPCO in its comments, an analysis of high load factor rates must include an analysis of the relationship between the level of the demand charge and the energy charges.

Coincident Demand Billing

A customer's monthly demand charge is based on the customer's maximum demand at a single location. Customers that take electric service at more than one location would benefit from a lower total demand if their demand charge was based on the maximum coincident demand of each of the locations. This is because mathematically the maximum coincident demand of multiple locations must be less than or equal to the sum of the individual maximum demands. Therefore, if coincident demand billing is allowed, customers with multiple locations would most likely experience a decrease in their bills. Wausau Paper correctly points out that customers with lower load factors would find it easier to benefit from coincident demand billing. Wausau Paper supports coincident demand billing even though it has a high load factor. Coincident demand billing would enable Wausau Paper to reduce its bills by engaging in load management and load shifting among its locations.

The Commission has approved coincident demand billing in certain circumstances where a customer takes delivery of service at more than one point on the same premises for the convenience of the utility. Coincident demand billing has also been allowed when a customer with multiple locations can coordinate demand reductions at these locations during interruptions.

The problem that coincident demand billing presents is that while customers with multiple locations will experience a decrease in their bills if billed on a coincident basis, the utility's cost to provide service is not reduced. This is a result of the fact that the on-peak demand charge is based on each customer's maximum monthly peak demand, which does not necessarily have a direct relationship with the utility's generation costs. This is especially true now that all large utilities under the Commission's jurisdiction in Wisconsin participate in the MISO Day 2 energy market. While coincident demand billing will decrease kW billing units and thus bills for participating customers, it does not reduce the utility's costs. If coincident demand billing were to be implemented, customers with only a single location would experience an increase in their bills to make up for the revenues lost to customers who benefit. There are also concerns about how it would be determined which customers would be eligible for coincident demand billing. There is clearly no basis for extending coincident demand billing for distribution demand charges because distribution and service facilities are sized for each metered location.

Although some large customers with multiple locations would clearly benefit from coincident demand billing, the Commission should be cautious about enacting it except in special circumstances where the reduction in billing units reflects an associated reduction in the utility's costs.

Interruptible Rates

The general structure for the interruptible rates offered by Wisconsin utilities was adopted in the early 1980s. Since that time, numerous provisions have been added to the interruptible rate schedules. Generally, these provisions have provided new options and additional flexibility for participating customers. In 1988, the Commission decided to base interruptible credits on the cost of peaking capacity. Although the amount of the interruptible credits have been continually contested in rate cases since that time, basing the credit on the cost of peaking capacity is still generally accepted.

The advent of the MISO Day 2 energy market will present opportunities and challenges for the current interruptible rate schedules. Prior to the Day 2 market, a utility's generation and purchases were matched with its own load. The interruptible rate schedules allow a utility to call for an interruption when a utility's generation resources or purchases are insufficient to provide for the utility's firm and interruptible loads. However, with the implementation of the MISO Day 2 energy market, utilities sell all of their generation into the market and buy all of their energy from the market. There is no direct match between a utility's generation and its load. Unless there is a region-wide capacity shortfall or there are widespread transmission problems, a utility can always buy more energy from the market, even if its own generation is not sufficient to serve its load. Although there will always be need to call interruptions to maintain system reliability during system emergencies, interruptions will more commonly occur during periods when LMPs are high. However, given the ready availability of energy from the market, utilities will be able to easily offer interruptible customers the option of "buying through" such interruptions. The Commission will need determine the price level at which economic interruptions should be called. WIEG recognizes this issue and suggests the adoption of a bidding mechanism to set trigger prices for interruptions. This issue will be discussed below under the discussion of Demand Response.

Real Time Pricing

Currently, NSPW and WEPCO are the only Wisconsin utilities that offer real time pricing. There is only one customer in Wisconsin that is served under a real time pricing rate schedule. The Commission staff is not aware of any requests by customers of the other utilities for the implementation of new real time pricing programs. A significant barrier to participation in real time pricing programs is the perception by customers that the potential savings from real time pricing are not outweighed by the risk of increases in electric costs or operational costs in relation to traditional fixed rates.

The Commission could conduct an evaluation of real time pricing and determine if there are ways to reduce the current barriers to participation on the current real time pricing rates or to implement new real time pricing rate structures. The LMPs from the MISO Day 2 market could clearly provide the basis for new real time pricing rate structures. The Commission could also evaluate the real time pricing rate structures offered in other states to determine whether these rate structures may be appropriate for Wisconsin. However, real time pricing programs in states that do not have an LMP-based energy market will likely not be an appropriate model for Wisconsin.

Demand Response Rates

All of the large investor-owned utilities in Wisconsin currently have electric service schedules that provide customers an opportunity to receive market based compensation for voluntary interruptions of service as required by Wis. Stat. § 196.192(2)(a). Generally, these service schedules provide that customers can receive a payment for load reductions when market prices are high. WIEG and CUB have expressed support for the continuation and possible expansion of these demand response programs.

The Resource Adequacy proposal currently being advanced by MISO relies on demand response by customers to reduce consumption during periods when capacity is short and LMPs are high. MISO has emphasized that demand response requires that retail customers be exposed to LMPs from the wholesale market. The current rate incentives for voluntary interruptions will need to be compatible with the MISO Resource Adequacy mechanism. The Commission could also investigate how the integration of a demand response pricing mechanism could be paired with a real time pricing rate structure, in which the customer would be exposed to real time rates only during certain high cost periods.

CUB and WIEG also express an interest in demand bidding. In demand bidding programs, customers submit bids based on a threshold price to reduce load during periods of high costs. The utility can then select the lowest priced bids that will achieve the necessary load reduction, or it can call on customers to voluntarily reduce load when their individual threshold is reached. Demand bidding has been implemented successfully in other states. The Commission could conduct an evaluation of demand bidding to determine whether it would be compatible with the provision of Wis. Stat. § 196.192(2)(a) and with the MISO Resource Adequacy proposals when these proposals are finalized.

Individual Contracts and Economic Development Rates

Wis. Stat. § 196.192(2)(b) provides that utilities can offer individual contracts to customers provided that the customer takes market risks and receives market benefits, and neither customers nor stockholders are harmed. These restrictions have effectively limited the use of individual contracts in Wisconsin.

WIEG suggests that the restriction in Wis. Stat. § 196.192 that other customers and stockholders not be harmed by an individual contract be eliminated and replaced with public interest standard that takes into account economic and employment benefits. Such a change is opposed by the utilities, which fear that stockholders would be forced to bear the burden of any revenue reductions that might result from an individual contract that is not as profitable as the standard rate offerings. CUB is concerned that individual contracts raise concerns about rate discrimination, including discrimination that may harm actual or potential competitors.

WIEG, Wausau Paper and MGE support the use of special contracts because such a contract can be tailored to meet specific loads or service characteristics of customers. Other stakeholders prefer to provide alternatives that would meet any such needs in service schedules so that such offerings would be available to all customers. There may be potential to offer individual contracts based on MISO Day 2 market prices to customers that operate generating facilities that would meet the criteria of Wis. Stat. § 196.192. Most likely this would entail some mixture of real time prices and non-firm service. The Commission has approved an individual contract between Georgia Pacific and WPSC. This contract allows Georgia Pacific to operate generation at one paper mill to avoid the need to make interruptions at a second mill.

Economic development rates can provide a benefit to non-participating customers if a utility has significant excess capacity. Margins on additional sales that would not otherwise occur without the existence of the economic development rate can be used to reduce rates for other customers. Economic development rates are problematic because Wisconsin utilities are currently in a construction phase and do not have excess capacity. Economic development rates also present concerns relating to the provision of a competitive advantage to new customers entering a utility's service territory which compete in the same markets with existing customers, and in providing an economic advantage to one utility in its ability to attract new load versus other utilities.

Other than from WIEG and WPSC, there is little stakeholder support for the implementation of economic development rates in Wisconsin at this time. It is also not clear if the Commission has the statutory authority to authorize economic development rates. The Commission could state that it is willing look at any proposal for an economic development rate if it can be shown that non-participating customers would not be harmed. CUB is willing to support targeted energy efficiency spending for new load under the umbrella of an economic development rate. However, it is not clear if CUB would support energy efficiency spending to attract new load for economic development purposes if there was no benefit of the new load to non-participating customers.

Commission Alternatives

Alternative One: The Commission could direct Commission staff and the utilities to examine the issues associated with unbundling transmission and generation costs in rates.

Alternative Two: The Commission could direct Commission staff and the utilities to examine alternatives to the current demand charge and the 15 minute time interval of demand for collecting generation and transmission costs.

Alternative Three: The Commission could direct Commission staff and the utilities to investigate the use of additional pricing periods so that energy charges can more closely match market costs.

Alternative Four: The Commission could direct Commission staff and the utilities to conduct an analysis to determine whether high load factor customers impose lower costs on the utility.

Alternative Five: The Commission could direct Commission staff and the utilities to investigate the real time pricing rate structures offered in other states to determine whether any of these rate structures might be appropriate for Wisconsin.

Alternative Six: The Commission could direct Commission staff and the utilities to evaluate the use of demand bidding to determine whether it would be compatible with Wis. Stat. § 196.192(2)(a) and with the MISO proposal to utilize customer demand response as part of its Resource Adequacy plan.

Alternative Seven: The Commission could indicate it is willing to consider proposals for special contracts and economic development rates in which non-participating customers would not be harmed.

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Appendix A

SUMMARY OF COSS ALLOCATION POSITIONS

1. Production costs should be allocated using both capacity and energy allocators.
Use both Demand and Energy to Allocate Costs = D/E
Use only Demand to Allocate Costs and Exclude Interuptible = D

Alliant	MGE	NSPW	We Energies	WPSC	CUB	Wausau Paper	WIEG/WPC	WPPI
D	D	D/E	D/E	D	D/E	D	D	D/E

2. A 12 CP allocator is used but a better allocator based on more hours than any of the "CP" approaches should be investigated.
All agree with basic concept that a better allocator should be investigated.

Alliant	MGE	NSPW	We Energies	WPSC	CUB	Wausau Paper	WIEG/WPC	WPPI
12 CP	12 CP	12 CP	12 CP	12 CP	12 CP	Noncoin. kW	4 CP	12 CP

3. Energy is the best allocator for allocating fuel expenses.
All agree but disagree on whether or not to weight the energy allocator used.

Alliant	MGE	NSPW	We Energies	WPSC	CUB	Wausau Paper	WIEG/WPC	WPPI
Agree	Agree	Agree	Agree	Agree	Agree	Agree	Agree	Agree

4. Purchased Power Agreement costs should be allocated to classes in a manner that reflects the contracts related to a specific purchase.
All agree but some disagreement on whether or not to exclude interruptible loads from demand allocator.

Alliant	MGE	NSPW	We Energies	WPSC	CUB	Wausau Paper	WIEG/WPC	WPPI
Agree	Agree	Agree	Agree	Agree	Agree	Agree	Agree	Agree

5. The allocation of capacity-related costs should made using allocators that treat all loads as firm.
Include I = Treat all loads as firm and include all loads in demand allocator and make separate adjustments for interruptible load.
Exclude I = Exclude Interruptible loads from the demand allocator

Alliant	MGE	NSPW	We Energies	WPSC	CUB	Wausau Paper	WIEG/WPC	WPPI
Exclude I	Exclude I	Include I	Include I	Exclude I	Include I	Exclude I	Exclude I	Include I

6. A Coincident Capacity allocator should be used to allocate transmission costs.

Alliant	MGE	NSPW	We Energies	WPSC	CUB	Wausau Paper	WIEG/WPC	WPPI
12 CP Exclude I	12 CP Include I	12 CP Include I	12 CP Include I	12 CP Include I	12 CP Include I	Noncoin. kW	4 CP Include I	12 CP Include I

7. There are two basic approaches to allocating Distribution costs. These are Minimum System and Location.

Alliant	MGE	NSPW	We Energies	WPSC	CUB	Wausau Paper	WIEG/WPC	WPPI
Min. Sys.	Min. Sys.	Min. Sys.	Min. Sys.	Min. Sys.	Location	Min. Sys.	Min. Sys.	Min. Sys.

8. Energy efficiency costs should be directly assigned to the class incurring the costs.
Specific Ex. = Some programs may warrant exception to general rule.

Alliant	MGE	NSPW	We Energies	WPSC	CUB	Wausau Paper	WIEG/WPC	WPPI
Agree Specific Ex.	Agree	Agree	Agree	Agree	Agree Specific Ex.	Disagree	Agree	Disagree

9. Indirect A&G costs should be allocated to classes in the same fashion as costs are incurred by all other utility costs, excluding fuel and purchased power costs.

Alliant	MGE	NSPW	We Energies	WPSC	CUB	Wausau Paper	WIEG/WPC	WPPI
Agree	Agree	Agree	Agree	Agree	Use Energy	Agree	Agree	Agree

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